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APRIL 1988

ELECTRIC LIGHT & POWER

EL&P

Volume 66, Number 4
A PENNWELL PUBLICATION

VOICE OF THE ELECTRIC UTILITY INDUSTRY

FERC poses 'fine tuning' to increase competition

Mark T. Hoske
Assistant Editor

WASHINGTON—The Federal Energy Regulatory Commission proposed three rulemakings intended to increase competition for non-utility power production under PURPA, on March 16. Interested parties will have from 60 to 120 days to file comments before the commission votes on the measures.

Summary drafts of three notices of proposed rulemakings—on administrative avoided cost, competitive bidding and independent power producers—were made available at a Feb. 17 commission meeting, but interested parties have filed about 11,000 pages of testimony on possible PURFA revisions since 1985. (See related story, page 11.)

FERC Chairwoman Martha Hesse described the drafts of the proposed rulemakings as "fine tuning" the Public Utility Regulatory Policies Act of 1978. FERC hopes to create a more competitive and consistent regulatory framework of policies for the states to apply concerning non-utility generators, she has said.

The National Association of Regulatory Utility Commissioners took exception to the FERC drafts on March 2 at their winter committee meeting. The executive committee voted 21-0 to approve a resolution recommending, in part, that FERC terminate proposed rulemaking on competitive bidding or independent power producers and instead proceed with rulemaking on transmission regulations.

NARUC also asked that FERC allow a 120-day comment period to give interested parties time to develop responses and participate in the rulemaking proceedings. In addition to the 120 days, 30 more days should be allowed to file replies, with regional hearings on the proposals after that. FERC had said a 60-day reply period was being consid-

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LATE NEWS

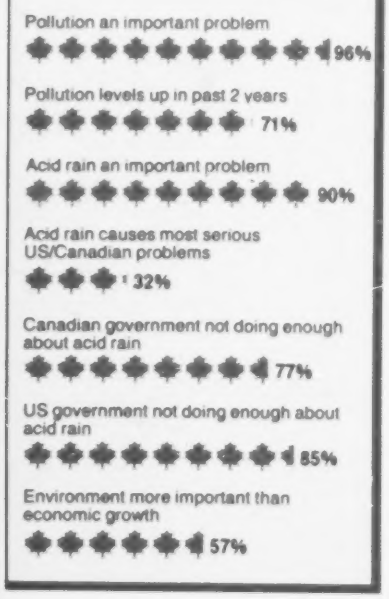
FERC has proposed three rulemakings related to PURPA. The rulemaking on avoided cost has a comment period of 60 days. Those on competitive bidding and IPPs have 90-day comment periods. A public conference is set for 110 days and reply comments for all three must be submitted within 120 days. See stories below and on page 11.

Virginia Power Co. announced reorganization of power operations, construction, engineering and technical support programs, resulting in elimination of 100 salaried positions in a transition toward acquiring more outside generation. See story, page 3.

A new communications network now links the 43 upper Midwest utilities in the Mid-Continent Area Power Pool. Designed and installed by Digital Equipment Co., the network also is connected to power pools to the south.

CANADIAN ATTITUDES

Canadian citizens are getting impatient with both the U.S. and their own federal governments when it comes to actions to reduce acid rain, according to a poll conducted by a Toronto public opinion polling company. Environics Research conducted a poll in late '87 for the Canadian Electrical Association that also indicated the citizens' concern over nuclear power—nearly two-thirds of the 2000 surveyed opposed construction of new nuclear power stations. Their attitudes about pollution are displayed below.



States study least-cost plans to aid cost-effective spending

WASHINGTON—Least-cost planning seems to be a hot topic, however one defines it.

From January 1986 to June 1987:

- 23 state regulatory commissions were examining or initiating policy,
- 12 state legislatures introduced or passed legislation,
- and six states have released studies about least-cost planning, according to a recent study from the Energy Conservation Coalition, affiliated with Environmental Action Foundation.

The 85-page report, "A Brighter Future: State Actions In Least-Cost Electrical Planning," is largely a documented, state-by-state review of those actions, but also includes a summary of the findings, an analysis of issues and appendix of contacts.

"Interest in least-cost planning among citizens, regulators and utilities is piqued because of rising electricity costs, increase small power production and the financial difficulties facing many nuclear power plants," according to Paul Markowitz, the ECC state field coordinator.

The ECC report defines least-cost strategy as a "mix of demand-side (energy efficiency and load management) and supply-side (small power sources and new generating facilities) resources [illegible] provide reliable [illegible]tricity at the low- [illegible] possible cost to [illegible]lities and their rate- [illegible]ers."

[illegible]urther, least-cost planning assures that the cost-effective potential for all resources is assessed, and that resources are ranked accord-

Continued on page 12

Regulators, utilities seek DOE waste fund payments

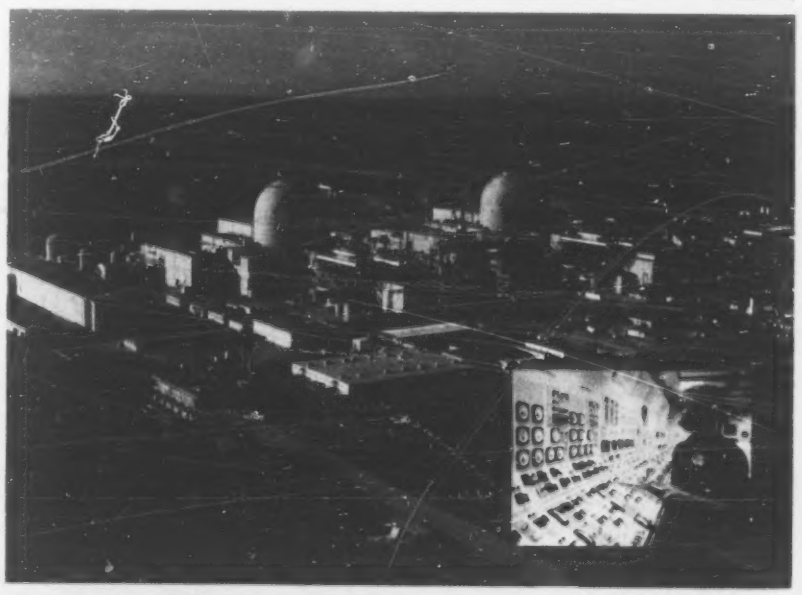
WASHINGTON—State regulators and nuclear utilities in February filed briefs with the U.S. Court of Appeals, continuing litigation over the U.S. Department of Energy's non-payment into the Nuclear Waste Fund. Oral arguments are scheduled for May 13.

Utilities and ratepayers have contributed $3.4 billion of the estimated $30 billion required for developing and operating high-level nuclear waste storage facilities.

The National Association of Regulatory Utility Commissioners (NARUC) and a group of 41 nuclear-plant owners contend that statutes require firm, fixed rules on payment schedules and the method of allocation. DOE has devised a method of payment into the fund which would treat common costs of civilian and defense nuclear waste storage in a variable way, explained Charles D. Gray, assistant general counsel for NARUC.

NARUC and the utilities say those

Continued on page 10



South Texas to feed HL&P grid

Houston Lighting & Power hoped to get Unit 1 of its South Texas Project into full operation before this issue of *EL&P* reached readers. At press time, NRC investigators said alleged safety violations were not serious enough to delay a vote on full-power licensing. At left and in the background, a 7000-acre, man-made reservoir will provide cooling for the nuclear units. Unit 2 is 90-percent completed. HL&P operates and is 30.8-percent owner of the $5.3-billion, 2500-MW facility. Other owners are Central Power & Light Co. (25.2 percent) and municipal utilities of Austin and San Antonio. (See story, page 6.)

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News Briefs

JILL MINNER, Assistant Editor

TU Electric to purchase TMPA's share of Comanche Peak plant

Texas Utilities Co.'s principal subsidiary, Texas Utilities Electric Co., has agreed to buy Texas Municipal Power Agency's (TMPA) 6.2 percent share of the Comanche Peak nuclear power plant for $456 million. TU Electric also agreed to settle pending litigation, started in May 1986, between TMPA and the minority owners of Comanche Peak. Under the agreement, which is still subject to regulatory approval, TU Electric will make a series of installment purchases over the next five years for: TMPA's share of Comanche Peak, nuclear fuel, transmission facilities, and legal and other expenses related to the litigation.

Savannah shareholders approve acquisition by Southern Company

The acquisition of Savannah Electric and Power Co. by The Southern Co. was recently approved by Savannah Electric's shareholders. The utility will operate as an independent subsidiary of Southern Co. and will continue to be headquartered in Savannah, GA.

Ohio Transformer buys transformer repair business from Siemens

Ohio Transformer Corp. has purchased Siemens Energy and Automation's power transformer repair business. "We were looking for an opportunity to increase our market share as well as improve our already high performance level. The Siemens plant offers us state-of-the-art equipment and designs, a broadened customer base, and a quality, skilled workforce which will help us accomplish this goal," explained Ohio Transformer President Walter Wojack. The company said it will keep the facility at its present location and will take over operations immediately.

Dominion announces intent to buy one half of Enron Cogeneration

Dominion Energy, Inc., a subsidiary of Dominion Resources, Inc., has announced that it plans to buy one half of Enron Cogeneration Company. According to Enron Corp., the preliminary purchase price is $90 million. Enron Cogeneration reportedly has interests in three gas-fired cogeneration facilities totalling 915 MW.

PP&L plans to sell bulk power to BG&E

Pennsylvania Power & Light Co. (PP&L) has agreed to sell 125 MW of power to Baltimore Gas and Electric Co. for a 10-year period beginning in 1991. Under the contract, PP&L will sell 6.6 percent of the output from its share of the Susquehanna nuclear power plant. PP&L is currently selling that power to Atlantic Electric under an agreement which expires on Sept.30, 1991.

PG&E, TID submit power sales agreement for FERC approval

The Federal Energy Regulatory Commission (FERC) has been asked to approve a 20-year interconnection and power sales agreement between Pacific Gas and Electric Co. (PG&E) and the Turlock Irrigation District (TID) in San Francisco. Under the agreement, TID would have access to alternative power suppliers but would be required to purchase two percent of its electricity needs from PG&E over the next 20 years. "This contract responds to FERC's efforts to increase competition and decrease regulation in bulk power markets, by building market-based pricing into every coordination transaction," said Robert J. Haywood, PG&E vice president of power contracts.

Ferranti International, China contract for EMS

Ferranti International Controls Corp. has signed a 85-million contract with the Guangdong General Power Co. (GGPC) of the People's Republic of China for the supply of a Ranger Energy Management System in GGPC's service area. According to Ferranti, GGPC provides service to 60 million people in an area of Southern China near Hong Kong. The company has scheduled delivery of the system for mid-1989.

DOE asks for clean coal technology proposals

As part of its *Innovative Clean Coal Technology Program*, the Department of Energy is requesting proposals for clean coal technology projects. DOE said it will provide $536 million in funding to demonstrate the new technologies, but that private proposers must be willing to finance at least half the costs of the design, construction and initial operation of the demonstration facility. Proposals are due by May 23, 1988 and selection of the projects will take place in the early fall, according to DOE. Copies of the formal call for proposals, contained in DOE's *Program Opportunity Notice*, can be obtained by writing DOE at P.O. Box 2500, Attn: Document Control Specialist, MA-451.1, Washington, DC 20013.

Bechtel, BNFL join for nuclear fuel cycle work

Bechtel Limited (BL) and British Nuclear Fuels plc. (BNFL) have entered into a protocol agreement to work together on nuclear fuel cycle programs. "I believe that this association is an ideal combination of BNFL's expertise in the development, design, construction and operation of nuclear fuel facilities with Bechtel's wide-ranging engineering experience," stated Bill Wilkinson, BNFL's Deputy Chief Executive and Director of Engineering. The 15-year agreement calls for both companies to provide their skills and experience, while still allowing each firm to carry out its own marketing programs. "This landmark agreement combines the strongest, most diverse experience available in nuclear fuel cycle work," said BL Managing Director Ken Turnbull. London-based BL is a Bechtel operating company and will be assisted in its work by Bechtel National, Inc. of San Francisco.

Paquette to succeed Everett as head of Philadelphia Electric

Philadelphia Electric Co. has named Joseph F. Paquette, Jr. to succeed James Lee Everett III who has resigned as chairman. Paquette will leave his position as president of CMS Energy Corp. to help Philadelphia Electric deal with its troubled Peach Bottom nuclear plant, according to the utility. In addition, S. Kinnie Smith, Jr., currently vice chairman of CMS Energy Corp., will replace Paquette as president.

Niagara Mohawk names Endries president; Donlon chairman/CEO

Niagara Mohawk Power Corp. has announced that on June 1, William J. Donlon will succeed the retiring John G. Haehl, Jr. as chairman and CEO of the company. Donlon is currently president of Niagara Mohawk. Also on June 1, Niagara Mohawk Executive Vice President John M. Endries will become president. "We have taken all of the necessary actions to ensure an orderly management transition," noted Haehl. "In November, we announced a corporate restructuring and a new management team. My retirement and the elections of Bill Donlon and Jack Endries are the final steps in this transition," he added.

White, Katlic to head AEP coal companies

W.S. White, Jr. was named chairman and John E. Katlic was appointed president of American Electric Power Co.'s 11 coal companies. White, formerly president, will continue to serve as CEO. Katlic, who had been executive vice president, will carry on his responsibilities as chief operating officer of the companies.

Lee wins Gantt Medal

The American Management Association (AMA) and The American Society of Mechanical Engineers have named William S. Lee III as recipient of the 1987 Henry Laurence Gantt Medal. AMA said that Lee, who is Chairman and CEO of Duke Power Co., was chosen for his "distinguished achievement in management as a service to the community." The annual award will be presented this month at AMA's Human Resources Conference and Exposition in Chicago.

EPRI High Sulfur Test Center receives award

The High Sulfur Test Center (HSTC) has been selected as one of 1987's six outstanding engineering achievements by the National Society of Professional Engineers (NSPE). The HSTC, designed and managed by the Electric Power Research Institute, received the honor for "achievements that will contribute to public safety and welfare, provide the basis for future technological developments and contribute to our technological competitiveness," according to NSPE. "The goal of the 10-year, $65-million HSTC test and development program is to cut the cost of emission control by 50 percent, increase air-pollution control equipment reliability and develop methods that can convert the emissions into useful byproducts, such as gypsum wallboard or elemental sulfur," explained Kurt Yeager, EPRI vice president and director of the coal combustion systems division.

Generation growth will slow in '88, says EIA

In its *Short-Term Energy Outlook*, the Energy Information Administration (EIA) predicts that U.S. electricity generation growth will slow to about one percent between 1987 and 1988, due to slower industrial output and a return to normal weather. The administration reported that in 1987, a combination of relatively high growth in industrial output and a warm summer increased electricity generation from the previous year by three percent. EIA also projects that U.S. petroleum demand will increase for the third straight year.

Ohio electricity sales were up in 1987: OEUI

The Ohio Electric Utility Institute (OEUI) has reported that Ohio's electricity sales in 1987 increased by 5.2 percent. Industrial sales rose an average 6.6 percent and residential and commercial sales each showed a 3.9 percent increase. "This is clear evidence of Ohio's continued economic expansion as well as a reminder of the importance of anticipating our customers' electricity needs as we approach the 1990's," stated OEUI Executive Vice President Gerald M. Minnery. OEUI is the association of Ohio's eight investor-owned electric utilities.

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Virginia Power requests bids for 1750 MW

RICHMOND, VA—Virginia Power Co. is seeking bids of up to 1750 MW from outside generators of electricity, underscoring its commitment to use the bulk power market instead of building its own new generation.

"We believe that this will be the largest block of capacity yet purchased by a utility under competitive bidding," said Jack H. Ferguson, president and CEO of Virginia Power.

More planned

In addition, the utility announced plans to buy 5800 MW—30 percent of its generation—from outside sources by the year 2000.

These competitive purchases follow a January order by state regulators that encourages competitive bidding under PURPA and Federal Energy Regulatory Commission guidelines.

VP's bidding system and contracts are subject to review by state regulators and the utility reserves the option to reduce the amounts. Bids from independent power producers, cogenerators, small power producers and neighboring utilities will be evaluated on the basis of price and non-price factors. Contracts are to be awarded in October.

The need for new generation is a result of a growing sales base. Virginia's solid economic expansion and increased usage brought on by sharp declines in the company's electric rates relative to inflation, Ferguson explained.

By 1994, 2782 MW will be needed to keep pace with projected demand, VP said. More than 90 percent—2526 MW—is expected to come from non-company sources.

A departure

This is an obvious departure from previous utility tradition of building new generation capacity.

"Times have changed," Ferguson stated. "Economies of scale have vanished, and building new units has become expensive and risky. Changing economic and regulatory conditions have pushed utilities toward units with shorter lead times and smaller sizes."

The power is to be added over five years in seven varied amounts, starting with 150 MW in 1989.

PSNH assets for sale? LILCo talks go on

BARRINGTON—Managements of three northeastern utility companies beleaguered by nuclear plant problems continue to seek solutions, with varied results to report during late February and March.

Public Service of New Hampshire, Boston Edison and Long Island Lighting all face questionable futures as a result of their inabilities to get their respective nuclear plants into operation.

New England Electric System (a 10-percent Seabrook owner) is holding preliminary discussions with PSNH to acquire that utility's operating assets, excluding PSNH's 35.6-percent Seabrook stake.

Sales of these assets would help PSNH pay off its debts, but the bankruptcy court would have to approve, in addition to the usual state and federal approvals. Current market value of PSNH is $2.95 billion, or $1.15 billion without its $1.8-billion Seabrook investment.

Leaders in both utilities expressed optimism about the talks, though none would offer specific details. Observers suggest that the physical relationship of the two companies may favor merger action. NEES transmission lines traverse PSNH territory, and the utilities share a common border between Massachusetts and New Hampshire.

By the end of May, 120 days after filing for Chapter 11 bankruptcy, Public Service of New Hampshire must have a reorganization plan completed for the court. No details on that plan yet are available. A company spokesperson said extensions may be sought.

Boston Edison's Pilgrim

Boston Edison Co. plans to complete its self-assessment for restart of the 678-MW Pilgrim nuclear plant by the end of March. The assessment is to address various NRC concerns raised since the company's restart plan was submitted in July 1987. A final NRC go-ahead may take till May, or longer.

A BE spokesperson said a $165-million investment has been made in modifications, maintenance, and fuel loading for the plant, which was shut down in April 1986. However, an outside source pointed out that the company's cash flow problems had resulted in severe cutbacks in personnel and work levels aimed at correcting the plant's problems and could further delay NRC action.

Replacement power has cost about $178 million, an estimated $250,000 per day.

Modifications include:

- Adding a hydrogen chemistry system to improve steam water quality in order to reduce stress and corrosion cracking in piping joints.
- Replacing containment building spray headers to lower the flow rate and improve cooling capacity.
- Installing a third diesel generator for safety system backup power, exceeding NRC requirements. A second diesel fire water pump was added and security barriers were improved.
- About 80 percent of the plant now is radioactively "clean," up from 46 percent at shut down.

Power needed in New England

"New England needs new electricity generating capacity, including the Seabrook nuclear plant," says Samuel Huntington, president and CEO of NEES and chairman of New England Power Pool's executive committee.

The strong New England economy fueled a sharp 5.3-percent increase in total electricity use for 1987, which contributed to regional electricity shortages last summer and this winter, he explained.

Huntington cautioned against what he called "the triple threat"—Seabrook not receiving an operating license, the shutdown of nuclear facilities in Massachusetts, and any delay in completion of the second phase of the Hydro-Quebec transmission project scheduled for late 1990. These amount to almost

Continued on page 17

Rancho Seco fate unclear; SMUD voters to decide

SACRAMENTO, CA—Voters of the Sacramento Municipal Utility District will choose the fate of Rancho Seco, the board of directors decided, after it received conflicting advice from two panels on whether or not the troubled nuclear unit should operate, and if so, under what conditions.

More than $430 million has gone into plant restart since the December 1985 emergency shutdown. Before this issue of *EL&P* reaches its readers, the Nuclear Regulatory Commission was scheduled to vote on Rancho Seco's restart.

Referendum slated

Plant opponents have placed an item on the June ballot for voters to choose between continued operation or closing the plant. But the SMUD board decided to pose a referendum that would place strict guidelines on plant operations, including an option for voters to close the plant at refueling—18 months after full-power operation has begun.

The utility's general manager, Richard K. Byrne, and an appointed advisory panel, dubbed the Quest Team, concurred that the plant is too risky to operate and should be closed.

Another appointed advisory board made up of judges and statesmen, conducted separate hearings and unanimously recommended restart. Community leaders have expressed mixed views and public opinion polls are about even.

Recommendations from Byrne and the Quest Team include:

- Close Rancho Seco.
- Raise rates by 7 percent to pay for decomissioning and replacement power.
- Develop a program to assist the 600 to 700 people out of about 900 at the plant who would out of work.
- Arrange for a bond issue or other financing to fund those moves.
- Continue to negotiate with Pacific Gas & Electric and Southern California Edison for purchase of replacement power.
- Implement aggressive load management and conservation steps.
- Hold the April and May 1988 budgets to those of 1987.

The second advisory panel said, however, that there is no question that the plant is safe, and that operation, given the investment already made toward restart, is the choice most beneficial for economy and ratepayers.

Voters' option

The choice outlined in the board's referendum would place a number of restrictions on operation:

- Operate Ranco Seco for 18 months, while pursuing options for divestiture.
- Strive for 70-percent availability after full-power operation is acheived.
- If operation falls below 50-percent for four successive months, the plant would close. The board could only keep the plant operating by a four-to-one vote. The board may close the plant by four-fifths vote prior to the first refueling.
- Performance would be evaluated every six months by an outside consultant.

Continued on page 10

1987 electric utility financings fell 33 percent, says consulting firm

NEW YORK—Financings by all types of utilities fell 43 percent in 1987 from the previous year. Electric company financings, including the sale of bonds, preferred stock and common shares, dropped 33 percent. Gas financings were down only 8 percent, according to Ebasco Business Consulting Co.

The firm's tabulation showed total 1987 financings of $21.1 billion, down from 37.2 billion in 1986. Moreover, in 1986, electric utilities *alone* raised $23.7 billion, surpassing the 1987 combined total raised by *all* types of utilities.

Most of the financings were public in nature and were sold on a negotiated basis. About two-thirds of the amount was new money and the balance for refunding purposes.

Largest cutbacks were in telephone and water utility financings—down by 85 and 72 percent, respectively.

INVESTOR-OWNED UTILITY SECURITY OFFERINGS ($000 — 1987 vs 1986)

	JANUARY 1, TO DECEMBER 31, 1987									
	TOTAL	% CHANGE	ELECTRIC	% CHANGE	GAS	% CHANGE	TELEPHONE	% CHANGE	WATER	% CHANGE
TOTAL FINANCING	21,074,946	(43)	15,910,132	(33)	3,758,274	(8)	1,390,000	(85)	16,540	(72)
LONG-TERM DEBT	18,352,487	(47)	13,706,382	(36)	3,244,405	(16)	1,390,000	(85)	11,700	(22)
PREFERRED STOCK	2,364,125	40	1,958,000	17	406,125	∞	0	—	0	(100)
COMMON STOCK	358,334	(68)	245,750	(62)	107,744	(52)	0	(100)	4,840	(89)
BY TYPE OF SALE										
PUBLIC	19,060,746	(47)	15,335,132	(34)	2,425,774	(36)	1,295,000	(86)	4,840	(89)
PRIVATE	2,014,200	60	575,000	(7)	1,132,500	257	95,000	(69)	11,700	(22)
BY PURPOSE OF SALE										
NEW MONEY	14,156,632	(14)	9,918,477	(17)	3,196,615	7	1,025,000	(28)	16,540	(72)
REFUNDING	6,918,314	(67)	5,991,655	(49)	561,659	(49)	365,000	(95)	0	—
BY METHOD OF SALE										
COMPETITIVE	4,765,125	(51)	4,285,125	(30)	0	(100)	480,000	(84)	0	—
NEGOTIATED	14,295,621	(45)	11,050,007	(35)	2,425,774	(22)	815,000	(87)	4,840	(89)
PRIVATE SALES	2,014,200	60	575,000	(7)	1,332,500	320	95,000	(69)	11,700	(22)

COMMENTARY

IPPs offer capacity at minimal risk to utilities

The electric utility industry is, for once, in a position where it can test the efficacy of a major change in the way it does business without assuming major risk. Over the next three to five years or so, utilities will have the oppportunity of testing whether they can provide adequate, economic and reliable power supplies without major investment in new generating facilities and the huge risks we have come to realize go with them...in effect have its cake and eat it too.

Emergence of Independent Power Producers formed with the sole objective of building and operating power plants with the outputs going to one or more electric utilities provide the foundation for this test, under PURPA.

No longer will service to utilities under PURPA be secondary or tertiary contractual arrangements by managements more interested in process heat, production-line output, or chemical thru-put, as with many cogenerators.

Managements of IPPs (and these may include subsidiaries of utility holding companies) can only succeed if they serve the electric utility well. The utility, or utilities, are and will be the sole customer(s) of the IPP. If the IPP managements can't compete in terms of cost and reliable service they will be out of business, plain and simple. For this reason, managements of IPPs are approaching the market with full awareness of the requirements, including the need for consistent, quality maintenance.

The opportunity to test the merits of using IPPs comes from the continuing surplus of generating capacity and the relatively low level of demand for new facilities over the next few years. While there may be need for new capacity, which IPPs can fill in a timely manner, the level will be such that only a small portion of total electric industry capacity will be involved. Should the experiment prove uneconomic or if the supply should be of unacceptable reliability, back-up replacement power will be available. Thus, utilities can conserve capital, move ahead with growth and system extension plans, and yet maintain reliable, economic service to customers without major capital investment. As Roger Sant, Chairman and President of Applied Energy Services, a large IPP, suggested recently, there will be no better time to test the approach. For utilities, it will be win-win situation.

Most utilities can be expected to adopt a wait-and-see attitude, exercising their normal conservatism. But an adventuresome few will get together with IPP managements to see if there aren't mutual benefits accruing to all from increased mutual cooperation.

Admittedly, it's a new tack for utilites to take, but the risks are far less for utility management than committing to build major new power supply facilities under today's regulatory uncertainties. And they are far fewer than in dealing with cogenerators of questionable capabilities and committment.

Robert A. Lincicome, Editor-in-Chief

Four nominated for Edison Medal

WASHINGTON—Four utilities have been nomonated for the Edison Award, the highest recognition given out by the Edison Electric Institute:

Baltimore Gas & Electric Co., for demonstrating corporate leadership through development of a broad range of educational and community service programs.

Consumers Power Co., for aggressive operational reorganization to recover from the near-fatal impact of its Midland Nuclear Plant, including formation of partnerships to convert and own the Midland combined-cycle plant and the Palisades Nuclear Plant, settling a variety of legal issues.

Pennsylvania Power & Light Co., for developmemt of a focused marketing program aimed at increasing area employment and kWh sales without increasing demand.

Virginia Power Co., for creative cotporate redirection to make non-utility power and diversification vital parts of its competitive makeup.

Correction notice

Last month in a lead New Product item, FlightSafety was erroeneously identified as a part of Singer Corp. FlightSafety is not related to Singer in any way, we have been informed.

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LETTERS

Changes ahead for electric industry

More letters on page 16

I am a bargaining unit employee of an electric utility in New Jersey,and I read my supervisor's copy of *Electric Light & Power*. I enjoy its thoroughness and fair reporting.

I am writing about your editorial in the December issue (p.4). I am in my 40s, and like your daughters I was fond of Bob Dylan and was supportive of the issues he sang about in songs like "The times, they are a-changing." Ironically, I am not sure that I like all the changes that seem to be coming for the electric utility industry.

You didn't mention the word "deregulation" specifically in your editorial, but it seems to be the main impetus behind most of the changes you describe. The bottom line to me seems to be that as an industry we no longer have as our priority providing reliable, reasonably priced electricity to our customers.

Now we are worried about competition, we're thinking about diversification and restructuring, and we're starting to behave like typical capitalist corporations. Now our most important customers are those large users who could perhaps buy their power from the cogenerators across the state or the power plant with the extra capacity out west.

We're starting to lay off employees and bargain harder with our unions to squeeze more efficiency out of the workers. But what will happen to the quality of service to individual customers like you or me? And if prices are lowered to keep the big customers, who will make up the difference? In the last sentence of your editorial you state "...the opportunities never have been brighter, either." Brighter for whom and in what way.?

Who benefits from changing the electric utility industry? Certainly not the senior citizens who have their money invested in what they believe to be secure, conservative utility stocks. You point out that diversification is risky. What makes utility executives think [that] because they have been successful in a non-competitive regulated businessthey can go out and be successful in fields and environments in which they have no experience? Why would they want to in the first place? Presumably if an individual executive wants the challenge of a competitive environment, he would not choose to work at a utility.

Certainly the changes will not benefit those employees who are being laid off or asked to do more work. If work crews are being reduced by layoffs or attrition, this doesn't bode well for the customers who depend on them for reliable electric power. Undoubtedly there are some people or companies who will make out very well if these changes come, but I think it is unlikely that they will be the people who are now executives or employees in electric utilities or the small customers of electric utilities.

I am writing this letter because I am upset with you as a trade publication and with the executives in the industry for not answering the question," Why change?" The feeling I get from what I read and from what I hear from executives in my company is that what is coming is coming, and we're powerless to do anything about it, so we're going to do what we can to get ready for it. That's fine up to a point, but how about answering the hard questions, and if the answer is that these changes are bad, then fight back. Speak out. Lobby. I get the feeling we're just passively laying here for this steamroller called deregulation to roll over us. What's even more disturbing is that when you ask questions, they don't even seem to know who is driving the steamroller!

I suppose the final verdict on deregulation of the phone company isn't in yet, but as an individual consumer and part of a corporate one, I can't see that the product has gotten any cheaper, and I know the quality of service is worse. If the change is marginally better or worse, I can't see any justification for the change. What is wrong with a company, such as the one I work for, that provides reliable electricity to its customers at reasonable rates, is sensitive to their needs, is involved in community affairs in many ways, and provides a good secure place of employment for thousands of people? Why should this change? So some entrepreneurs can have a chance to get rich quick? So some gigantic energy user can save a few bucks on their power costs? So some politician can look good for busting the power company?

I hope that your publication will address these questions and come up with some good anawers before it's too late. I think our industry, perhaps more than others, has an obligation to consider the results of possible changes in light of what's the best for our communities and our country.

John D. Bartram
Westfield, NJ

Editor's note: We share many of reader Bartram's concerns. However, the objective of the December editorial was more to cite the developments that will be affecting the electric utility industry in 1988 and beyond than to discuss their pros and cons.

We don't see deregulation as the trend, so much as reregulation, which may force substantial changes in the ways utilities conduct their business. There has been, and is, substantial opposition at every level to many of the changes discussed. But ultimately the question is not so much whether changes are coming, but when and how utilities can best accommodate to those changes.

Certainly not all utilities will be affected in the same way, nor to the same degree. The challenge for utility managements will be to determine where opportunities are presented that can favorably affect the utility's service to both customers and shareholders.

Society is changing in many ways. And as society changes, demands on the institutions that serve society will change. Institutions, and that includes electric utilities, must change to meet those new requirements, or must convince the groups of society they serve to let them continue in their old ways. The latter is highly improbable. If history teaches us anything, it is that when the desires and expectations of society change, institutions must bend to those changes or be swept away.

Simplifying LTC selection

I noted in your January 1988 edition of *EL&P* a letter from Mr. C.N. Pany of H.K. Porter, commenting on your article titled "Evalation method can ease LTC Selection," from October *EL&P*, p. 30. Even though I agree with Mr. Pany that the article treated the evaluation of on-load tap changere in a rather simplistic manner, I still feel that it made a very useful contribution by highlighting the fact that all on-load tap changers are not equal and that the cost of operation, over the life of the transformer, should be a part of the evaluation process.

Today, virtually every electric utility evaluates the worth of excitation and load losses, but, in my experience, very

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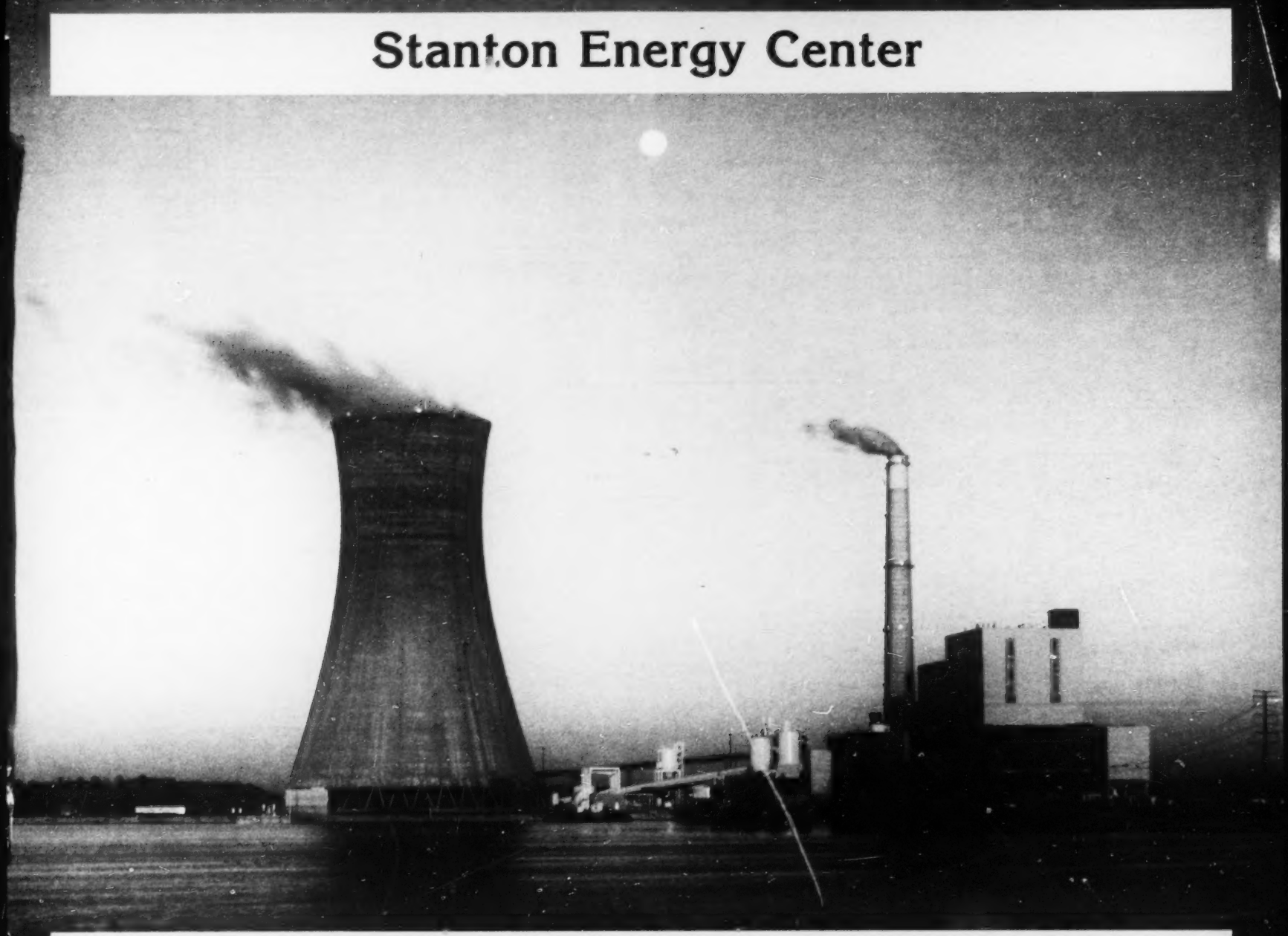
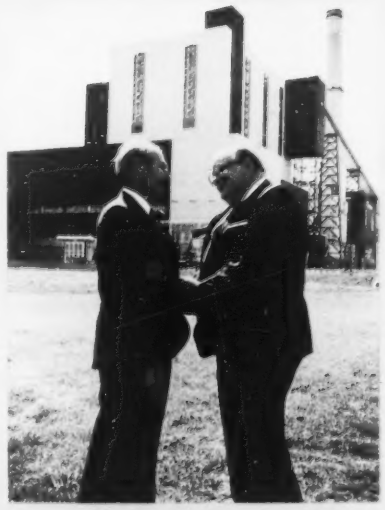


Florida Project On Budget, Ahead of Schedule

The Orlando-based Stanton Energy Center is the first all municipal, joint ownership power plant in Florida, serving more than 500,000 people from Jacksonville Beach to Key West.

The Orlando Utilities Commission (OUC) owns 68.6 percent of Stanton Unit 1 and operates and maintains the plant. The Florida Municipal Power Agency, with a 26.6 percent interest, represents 11 municipal members. The Kissimmee Utility Authority owns a 4.8 percent interest.

The 415 megawatt coal-fueled unit was complete three months ahead of schedule and on budget.



Worker injury rates were less than half the national average. There was no lost time due to labor-management problems. The unit was designed to utilize the latest power plant technology.

Black & Veatch was responsible for engineering design, construction management, and the worker safety program. Shown on site are Earl Windisch (l.), Black & Veatch partner, and Curt Stanton, OUC general manager from 1948 to 1983.

Black & Veatch, Power Division
P.O. Box 8405, Kansas City, Missouri
(913) 339-2000

Black & Veatch
Engineers-Architects

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Inquire R.S. 7

Plant construction is spiralling down, says UDI report

WASHINGTON—A survey of utility-owned, power-plant construction plans showed that U.S. utilities placed over 10,000 MW of new generating capacity into service in 1987. That was the good news.

The bad news was that this was far below the 16,000 MW put in service in 1986 and even under the 13,000 planned for 1988. But all three amounts soar above the projected amounts for 1989 and 1990, which are 8000 and 2200 MW, respectively.

What's going on

These numbers appear in the report from Utility Data Institute that is called "Projected Capital Costs: U.S. Electric Plants". As UDI's President Liz Hannon notes in the report, "The new central-station pipeline continues to empty at a rapid pace." Eight previously-planned, steam-electric units were removed from UDI's database last year.

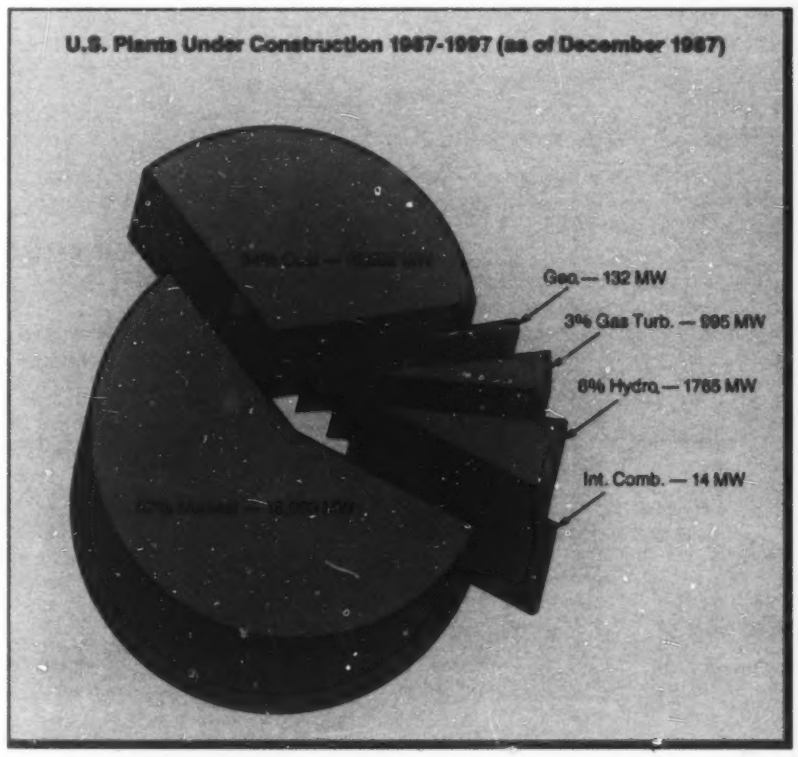
Again it is a bad news/good news situation, however. In this case, the good news is that escalations in estimates of new plants' capital costs have slowed. Noted Christopher Bergen, UDI's vice president, "...these new thermal and hydro units...are now coming in under budget, and on or ahead of schedule."

A little more good news is that new construction started on a utility coal plant for the first time in approximately five years. Site work began in November 1987 on a 150-MW, fluidized-bed, lignite-fired unit near Calvert, TX. It is to be turned over to the Texas-New Mexico Power Co. when completed.

Other action

On another related front, nearly 30 new gas-turbine peaking units were added to the total utility capacity in 1987.

The report also gives summary statistics on utility capital expenditures for fuel conversions, repowering, and life-extension activities. It indicates ongoing strategies to ensure cost-effective operation of existing plants in the face of steadily-eroding reserve margins.



Fossil plant performance better after 1974

PALO ALTO, CA—Availability of fossil-fueled power plants improved in the decade ending with 1984, after a substantial decline in the period from 1965-1974. However, according to an Electric Power Research Institute study, the 1984 performance level still trailed that of 1965 by about 6 percent.

While the performance of all fuel types fell through the mid-1970s, coal unit performance deteriorated more than either oil or gas units. But by the end of 1984, there was virtually no difference among the performances of coal-, oil- and gas-fired units.

EPRI reported that plant and component availability can have a huge impact on both individual utilities and the entire industry. A 1-percent improvement in availability for just a 100-MW coal-fired plant could result in a $1.5-million cost saving, depending on the utility's load profile and unit mix.

The study showed that vintage was an important factor. Within size ranges, more recently completed units generally performed better than older units.

Considering both size and vintage effects, the overall performance differential between sub- and supercritical coal units ranges from 1 to 2 percent. Recent availability of balanced draft units improved on that of pressurized (and never converted) sub- and super-critical units by 1.5 percent.

For oil and gas plants, the differential ranged between 5 and 10 percent.

Conversion to balanced draft operation appeared to improve the availability of both sub- and super-critical coal-fired units. After allowing for vintage and calendar-year effects, this improvement was reported to be 3-5 percent. However, since units prior to conversion were performing 6-10 percent below unconverted pressurized units, the improvement did not hit the level of either the unconverted or balanced-draft units.

Outage data from 1965 through 1984 were studied for 668 fossil-fueled units rated 200-MW and larger. These generating units covered approximately 7700 unit-years of experience. Analysis included overall unit performance, as well as the contribution of major equipment, such as boiler and turbine, to performance levels. Investigators consolidated the normal event code used by EEI into 53 cause code groups.

Water chemistry analysis course to be offered

COLUMBIA, MD—Improved performance and reliability of technicians and engineers engaged in water chemistry is the goal of a special course to be offered by General Physics Corp.

Course covers

The course GP is offering for the mid- to latter-part of the year is titled "Spectrophotometric Methods of Analysis in the Ultraviolet/Visible Range." Designed for technicians and supervisors, the 2 ½-day course will cover analytical methods, instrument components and performance characteristics.

For more information contact Lorin at General Physics Corp., 10650 Hickory Ridge Road, Columbia, MD 21044, or by calling (800) 638-3838.

Creepy crawler goes where other vehicles can't reach

LONDON—A low-profile inspection device developed by engineers at the Central Electricity Generating Board, the UK's national utility, has a novel articulated center section that enables it to climb into places other vehicles can't reach.

The SPIV (Steam Pipework Inspection Vehicle) is being used to check welds inside pipes and so eliminate the need to remove exterior lagging.

Crawl and squeeze

Armed with a minature camera, SPIV can crawl into pipework through 125-mm valves. It can squeeze through measuring nozzles just 100 mm in diameter. It then can film pipe runs, up to 150 meters, from the inside.

CEGB says the prototype device already has paid for itself. It has recovered its £25,000 hardware costs identifying main steampipe welds at the Padiham power station in northern England.

One-off operation

Geoff Frost, maintenance superintendent at the plant, says "This was a one-off operation as far as we are concerned. The alternative would have been to remove all the external pipe thermal insulation, then try to identify all the welds from the outside, a very difficult operation and a time-consuming one at that."

Missouri co-op tops record mine output

Associated Electric Cooperative Inc., which provides power to 40 electric cooperatives in Missouri, set a production record at its Thomas Hill, MO, mine last year. Some 2.4 million tons of coal were mined for the co-op's nearby generating station, surpassing the previous record by 20 percent. Associated's surface mines cover approximately 25,000 sq acres, with 400 acres mined annually. The G&T co-op, with 2300 MW of generating capacity, is the nation's largest wholesale supplier of power to RECs. Line truck (lower right) shows scale.

Idaho Power faces hydro shortage

BOISE, ID—Idaho Power Co.'s hydroelectric prospects have gone from bad to worse this year. Hydro generation, which represents a substantial portion of the utility's total sales and contributes to the company's ability to hold its own retail rates down, is drying up for the second year in a row, the utility says.

Projections

According to projections by the company's hydrologist, Scott Larrondo, the Spring runoff is expected to be less than half the 25-year average. With 16 hydro facilities in the Snake River basin, representing 60 percent of the company's total generating capacity, the shortage of runoff means the utility will have to depend more heavily on its more-expensive coal-fired generating units or buy power from neighboring utilities.

Low streamflow

The low streamflow also will mean that IPC will have little low-cost power to sell to other utilities for the second straight year. The company budgets some $68-million in revenues from its surplus energy sales. Without this, the company's rates to its own customers will not be adequate to provide a fair return to shareholders. Last year's revenues from surplus power sales were less than $20 million.